Aerospace Report No.
ATR-78(7698)-1, Vol I

# FEASIBILITY OF INSTALLING SULFUR DIOXIDE SCRUBBERS ON STATIONARY SOURCES IN THE SOUTH COAST AIR BASIN OF CALIFORNIA

## VOLUME I: EXECUTIVE SUMMARY

Prepared by

P. P. Leo and J. Rossoff

August 1978

Government Support Operations
THE AEROSPACE CORPORATION
El Segundo, California 90245

Prepared for

THE STATE OF CALIFORNIA
AIR RESOURCES BOARD
Sacramento, California 95812

Contract No. A6-211-30

## ABSTRACT


The feasibility and costs of flue gas scrubbing were determined for retrofitting eight selected oil-fired power plants and five industrial sources of sulfur dioxide ($SO_2$) emissions in the Los Angeles area. Sulfur dioxide scrubbing to achieve the equivalent of 0.05-percent sulfur oil (90 percent $SO_2$ removal from 0.5 percent sulfur oil) for the utility installations and the removal of approximately 90 percent $SO_2$ from the other sources were evaluated. The major emphasis on feasibility in this study was for physical installation of the scrubbers.

The power plants selected within the scope of this study represent approximately 80 percent of the fossil fuel-fired power plant generating capacity in the South Coast Air Basin. The $SO_2$ emissions from the five other sources studied are typical of boilers burning carbon monoxide in flue gas from fluid catalytic cracker units, petroleum coke calcining kilns, and sulfuric acid plants. They currently produce $SO_2$ emissions equivalent to approximately 18 percent of the emissions now being emitted from the eight power plants.

Technical feasibility for $SO_2$ removal was established on the basis of the lime-limestone nonregenerable scrubber technology demonstrated in Japan and on units currently being installed and operated in the United States. Other factors such as compatibility with facility operations, space requirements, waste handling, and disposal were examined. Power, water, and flue gas reheating requirements were also addressed.

It was concluded that all of the sites studied can be retrofitted with wet nonregenerable scrubbers capable of removing $SO_2$ to the levels specified. The degree of difficulty of the scrubber installations varied considerably. Some plants have relatively open areas near the stack, whereas others involve a difficult siting problem. Disposal of scrubber wastes produced from the scrubbers does not appear to present a significant handling problem or impact on existing Class I landfill disposal sites in Los Angeles County.

Capital investment estimates reflecting a range of retrofit complexity and redundancy factors are provided. Corresponding annualized charges in terms of mills per kilowatt hour, dollars per ton $SO_2$ removed, and dollars per ton product, as appropriate, are reported. The credit resulting from the burning of 0.5 percent sulfur oil by the utilities rather than the 0.25 percent currently in use is also identified.

This report was submitted in fulfillment of Contract Number A6-211-30 by The Aerospace Corporation under sponsorship of the California Air Resources Board. Work was completed as of June 30, 1978.

## ACKNOWLEDGMENTS

During the course of the study, contributions were made by numerous individuals in government agencies and in industry. The assistance and guidance of members of the California Air Resources Board staff, especially Mr. Jack Paskind, Senior Air Resources Engineer, are acknowledged.

Contributions in the form of operating information and site data were provided by the Los Angeles Department of Water and Power, Southern California Edison, Chevron, USA, Inc., Collier Carbon, Inc., Great Lakes Carbon, Inc., Martin Marietta Carbon, Inc., and Stauffer Chemical, Inc.

Sulfur dioxide scrubber information was provided by the Chemico Division of Envirotech, FMC Corporation, Peabody Process Systems, Pullman Kellogg, Research-Cottrell, and Air Correction Division of UOP, Inc.

Messrs. W. J. Swartwood and R. B. Laube of The Aerospace Corporation provided valuable assistance in the equipment siting and waste disposal assessments.

Appreciation is extended to all the contributors. However, assembly of the data, assessments, and conclusions drawn are the responsibility of the authors.

CONTENTS

## TABLES



## FIGURES

# 1. INTRODUCTION

The State of California Air Resources Board is evaluating the potential for reducing sulfur dioxide ($SO_2$) emissions from oil-fired utility power plants and other $SO_2$ sources in the Los Angeles area. This study has involved assessing the feasibility and cost of retrofitting flue gas scrubbers on utility boilers to achieve $SO_2$ removal equivalent to use of 0.05 percent sulfur oil (90 percent $SO_2$ removal from the burning of fuel oil containing 0.5 percent sulfur) and the reduction of $SO_2$ by approximately 90 percent from existing levels for other sources which include boilers burning carbon monoxide (CO) in the flue gas from fluid catalytic cracker regenerators, petroleum coke calcining kilns, and sulfuric acid units. These objectives are summarized in Table 1.

TABLE 1. SULFUR DIOXIDE REMOVAL OBJECTIVES

| Source | Objective |
|---|---|
| Utility boilers | 90 percent removal from combustion of fuel oil with 0.5 percent sulfur |
| Fluid catalytic cracker carbon monoxide boiler | 50 ppm maximum |
| Petroleum coke calcining kilns | 1.5 lb/short ton of coke charged into kiln |
| Sulfuric acid units | 4.0 lb/short ton of product acid |

A total of 13 study sites were selected by the research staff of the California Air Resources Board and are identified in Table 2. The eight utility power plants included in this study represent approximately 80 percent of the fossil-fueled electrical power plant generating capacity in the South Coast Air Basin.

TABLE 2. FACILITIES STUDIED

| $SO_2$ emission source | Agency or company and location |
| --- | --- |
| Electrical utility generating stations | Southern California Edison<br>Alamitos<br>El Segundo<br>Etiwanda<br>Huntington Beach<br>Ormond Beach<br>Redondo Beach |
| | Los Angeles Department of Water and Power<br>Haynes<br>Valley |
| Carbon monoxide boiler | Chevron, El Segundo |
| Petroleum coke calcining kilns | Great Lakes Carbon, Wilmington |
| | Martin Marietta Carbon, Carson |
| Sulfuric acid units | Stauffer Chemical, Carson |
| | Collier Carbon, Wilmington |

The technical feasibility assessment was based on determining the potential for 90 percent $SO_2$ removal by flue gas scrubbing. Existing demonstrated technology was considered a significant factor in assessing the $SO_2$ removal technology of scrubbing processes and their subsequent application to the various specific sites included in the study. Using this criterion, attention was focused on nonregenerative lime-limestone scrubbers that remove 90 percent of the $SO_2$. Such scrubbers are used extensively in Japan on oil- and some coal-fired boilers and in the United States on coal-fired units. The more complex and less developed regenerable processes were to be considered in the event that 90 percent removal efficiency was not achievable by means of first-generation, nonregenerable technology or if problems arising from the quantity or disposal of wastes produced from the nonregenerables made their application impractical.

The study involved a number of facets, including the following:

a. Assessment of scrubber technology
b. Characterization of the sites
c. Identification and assessment of scrubber system operation
d. Determination of site-specific feasibility and costs.

The approach taken to assess feasibility of installing $SO_2$ scrubbers is summarized in Table 3.

Assessment of the technology potential for the nonregenerable systems was based on evaluation of the results reported for the operational installations on numerous oil- and some coal-burning boilers in Japan and coal-burning units in the United States. Information developed through discussions with personnel knowledgeable of the details of the Japanese processes and those familiar with U.S. technology was used to augment the published data. Similar contacts were made with regard to the smaller scrubber units applicable to the industrial, nonutility installations.

For the data needed to evaluate each Los Angeles study site, information was derived from conferences with cognizant technical personnel from the various companies involved. The responses of various organizations

TABLE 3. SULFUR DIOXIDE SCRUBBER -- FEASIBILITY STUDY APPROACH

| Major areas of investigation | Specific tasks |
|---|---|
| Assess scrubber technology | Determine sulfur dioxide removal efficiency<br><br>Assess scrubber operability |
| Characterize power plants and industrial sites | Make on-site visits<br><br>Analyze responses to questionnaires defining plant characteristics and layout<br><br>Review plot plans and aerial photographs |
| Identify and assess scrubber system operation | Determine ability to reduce sulfur dioxide to required levels<br><br>Identify operating characteristics<br><br>Quantify operating requirements<br><br>Identify waste disposal impacts |
| Determine site-specific feasibility and costs (capital, operation and maintenance and annualized) | Obtain sizing, operating, and cost data from scrubber suppliers--Chemico, FMC (industrial), Peabody (industrial), Pullman Kellogg, Research Cottrell (utility and industrial divisions), and UOP<br><br>Consider effects of retrofit complexity and equipment redundancy on scrubber installations<br><br>Include cost benefits of using 0.5 percent sulfur oil instead of current 0.25 percent oil<br><br>Relate scrubber operating costs to selling price of product |

to questionnaires developed by The Aerospace Corporation were also used. Based on scrubber supplier inputs and published data, scrubber system requirements and operating conditions were identified and quantified. These included scrubber reagent, fresh water, power, and wastes produced by each of the sites. Further, by utilization of site plot plans, aerial photographs, and equipment sizing information provided by various scrubber suppliers, layout sketches were made showing size, location, and orientation of the scrubber modules, lime storage facilities, and the waste handling and holding facilities. In addition, major impacts or modifications to existing facilities as determined by a review of the plot plans and site visits were identified.

Based on budget-type information provided by the scrubber manufacturers for grass-roots installation, capital cost estimates for retrofitting the sites were prepared as a function of several levels of complexity. The costs associated with a number of levels of equipment redundancy were determined. Annualized charges were defined which included capital charges, scrubber system operation, and waste disposal. Costs associated with plant or unit shutdown for installation of scrubber equipment were not included.

# 2. SUMMARY AND CONCLUSIONS

The study was oriented towards determining the feasibility of installing $SO_2$ scrubbers on selected utility boiler and industrial emission sources in the Los Angeles area. Four basic considerations in assessing feasibility in this study were addressed:

a. Technical feasibility of 90 percent $SO_2$ removal
b. Scrubber process definition
c. Feasibility of scrubber system installations at selected sites
d. Cost of site-specific capital equipment, total capital investment, and annualized costs.

Thirteen sites, which included six Southern California Edison (SCE) and two Los Angeles Department of Water and Power (DWP) generating stations (Table 4) and five industrial boiler and process sites were studied. The latter included a boiler burning carbon monoxide (CO) in the flue gas from a catalytic cracker regenerator, petroleum coke calcining kilns, and sulfuric acid units (Table 5). In general, the $SO_2$ removal requirement used in the study was a nominal 90 percent removal. The current emissions and the specific $SO_2$ removal requirements to meet study objectives for the various sources are defined in Table 6.

## 2.1 TECHNICAL FEASIBILITY OF $SO_2$ CONTROL REQUIREMENTS

As a result of this study, it was concluded that 90 percent removal of $SO_2$ flue gas, originating from oil-fired utility boilers and from industrial processes, can be accomplished on the basis of existing nonregenerable scrubbing technology. Consistent removal efficiences of 90 percent or greater have been demonstrated in Japan, primarily on oil-fired and some coal-fired boiler installations. Currently, scrubber units are being installed on coal-fired units in the United States to meet 90 percent $SO_2$ control requirements. Removal efficiencies in excess of 90 percent have been demonstrated with some scrubbers installed on industrial combustion and process sources of $SO_2$ in the United States.

TABLE 4. ELECTRICAL UTILITY FACILITY CHARACTERISTICS

| Electric utility generating station | Generating capacity, MW | No. of units | Average capacity factor, 1976 |
|---|---|---|---|
| Southern California Edison | | | |
| Alamitos | 1,950 | 6 | 0.442 |
| El Segundo | 1,020 | 4 | 0.444 |
| Etiwanda | 904 | 4 | 0.498 |
| Huntington Beach | 870 | 4 | 0.434 |
| Ormond Beach | 1,600 | 2 | 0.454 |
| Redondo Beach | 1,602 | 8 | 0.15[a]/0.451 |
| Los Angeles Department of Water and Power | | | |
| Haynes | 1,633 | 6 | 0.667 |
| Valley | 526 | 4 | 0.158[b] |
| Total | 10,105 | 38 | 0.424[c] |

[a] 0.15 applies to Units 1 through 4; 0.451 applies to Units 5 through 8

[b] Units 1 and 2 were for 1975

[c] Weighted average (excluding a and b)

TABLE 5. PETROLEUM AND CHEMICAL PROCESSING FACILITY CHARACTERISTICS

| Installation | Unit size, tons/day | No. of units |
|---|---|---|
| Carbon monoxide boiler -- Chevron | a | 1 |
| Petroleum coke calcining kilns | | |
| Great Lakes Carbon | 900 (ea) | 3 |
| Martin Marietta Carbon | 960 | 1 |
| Sulfuric acid units | | |
| Stauffer Chemical | 300 (ea) | 2 |
| | 200 | 1 |
| Collier Carbon | 450 | 1 |
| Total | -- | 9 |

[a]Not available -- boiler rated at 250,000 lb/hr steam

TABLE 6. SULFUR DIOXIDE EMISSION CONTROL CONDITIONS CONSIDERED IN THIS STUDY

| Electrical utilities and industrial sources | Current | | Objectives | |
|---|---|---|---|---|
| | Status | Approximate emissions, ppm | Removal by scrubber, percent | Emissions |
| Electrical utility boilers -- DWP and SCE units | Sulfur content in fuel oil not to exceed 0.25 percent | 150 | 90 from combustion of oil with 0.5 percent sulfur | 30 ppm (approx.) |
| Carbon monoxide boiler -- Chevron | $SO_2$ content of flue gas emissions is a function of crude being processed, in the range of 150 to 400 ppm | 225 (avg) | 88 for 400 ppm inlet | 50 ppm maximum |
| Petroleum coke calcining kilns | | | | |
| Great Lakes Carbon | Emissions are function of crude: currently 300 to 380 ppm (approx. 1.3% sulfur in coke) | 300 (wet) | 88 for normal production rates and 300 ppm | 1.5 lb $SO_2$ per short ton of coke charged into kiln |
| Martin Marietta Carbon | 2.3 to 2.5 percent sulfur crude | 700 (wet) | 93 for 2.5 percent sulfur crude | |
| Sulfuric acid units | | | | |
| Stauffer Chemical | 300 to 500 ppm | 400 | 33 for Units 1 and 2<br>66 for Unit 3 | 4.0 lb $SO_2$ per short ton of product |
| Collier Carbon | 350 ppm | 400 | 15 (ave.) | |

## 2.2 SCRUBBER PROCESS DEFINITION

Since a significant data base exists to support the $SO_2$ removal capability of the lime-limestone nonregenerable process for the large utility installations, this process was selected for further evaluation and quantification. Nonregenerable lime scrubbing, rather than limestone, was chosen for process definition and quantification (Figure 1) because lime has smaller space and handling requirements. Consideration of limestone would not result in any fundamental changes to the results of this study because basic scrubber tower sizes are nominally the same for both, being determined by the volumetric flow and spatial velocity of the flue gas through the tower. However, for a given amount of $SO_2$ removal, approximately 100 percent more limestone ($CaCO_3$) reagent, by weight, would be required in contrast to lime ($CaO$) because of chemical differences in the reagent and the slightly lower limestone utilization. The limestone process would also require pulverizing facilities, which are not needed with lime, and approximately 5 percent more scrubber waste would be produced if limestone were used.

Because of the limited area available at certain sites and the experience in applying the double alkali process to industrial use, the latter process (Figure 2) was considered, in addition to lime scrubbers for the smaller, nonutility installations in this study.

Electrical power, water, and flue gas reheating requirements were defined. A generalized schematic summarizing the various operating conditions is given in Figure 3, and total quantities are provided in Table 7 for all sites studied.

Filtered scrubber waste totalling approximately 328,000 tons or 163 acre-feet would be produced annually by the eight utility sites. The industrial sources studied would add approximately 14 percent. The disposable waste from the lime scrubbers was estimated to contain 72 percent solids subsequent to vacuum filtration, the latter being accomplished at the scrubber site. Use of trucks to transport the waste to two Class I, geographically appropriate disposal sites in Los Angeles County was determined to be feasible with

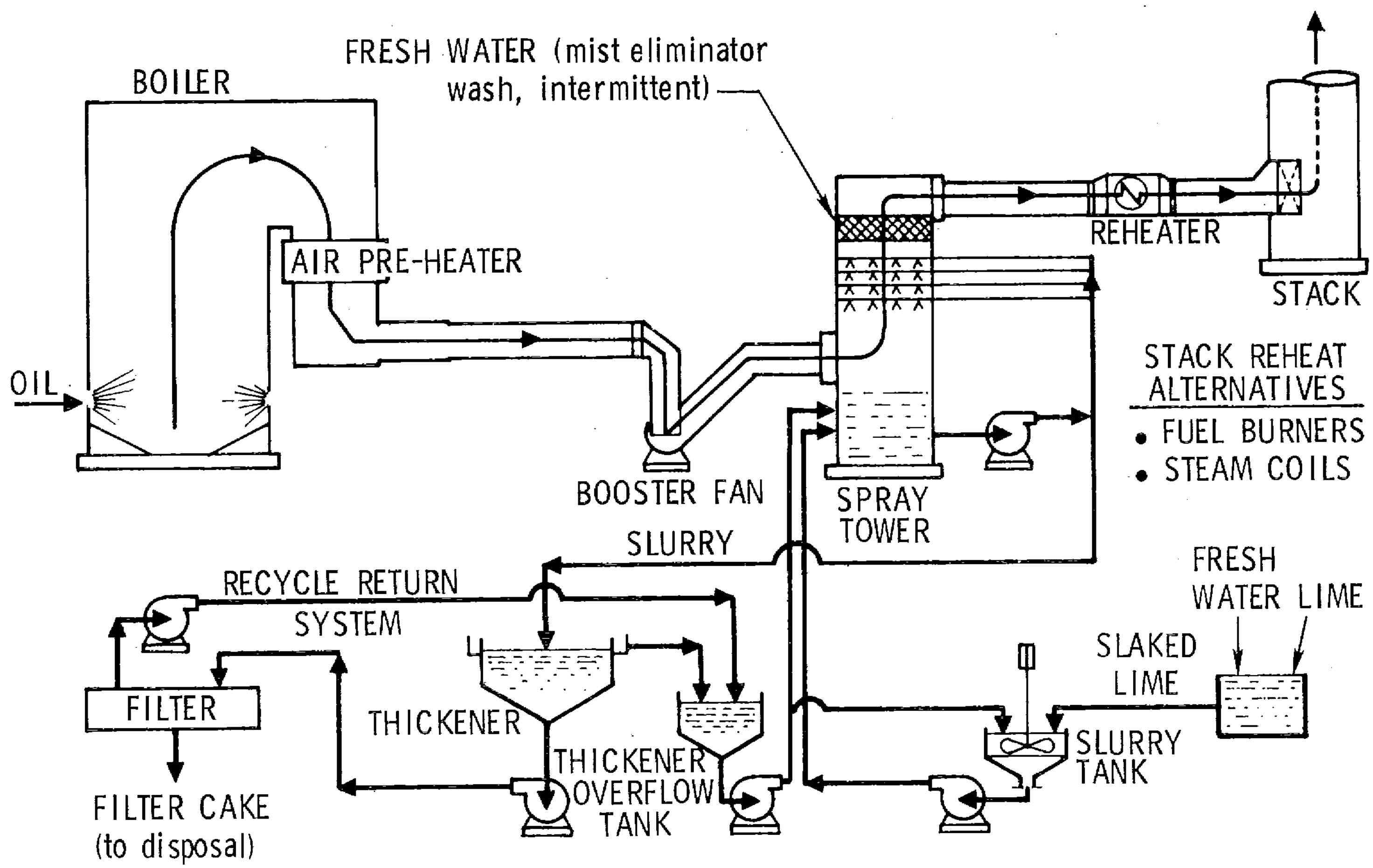


Figure 1. Lime scrubbing schematic

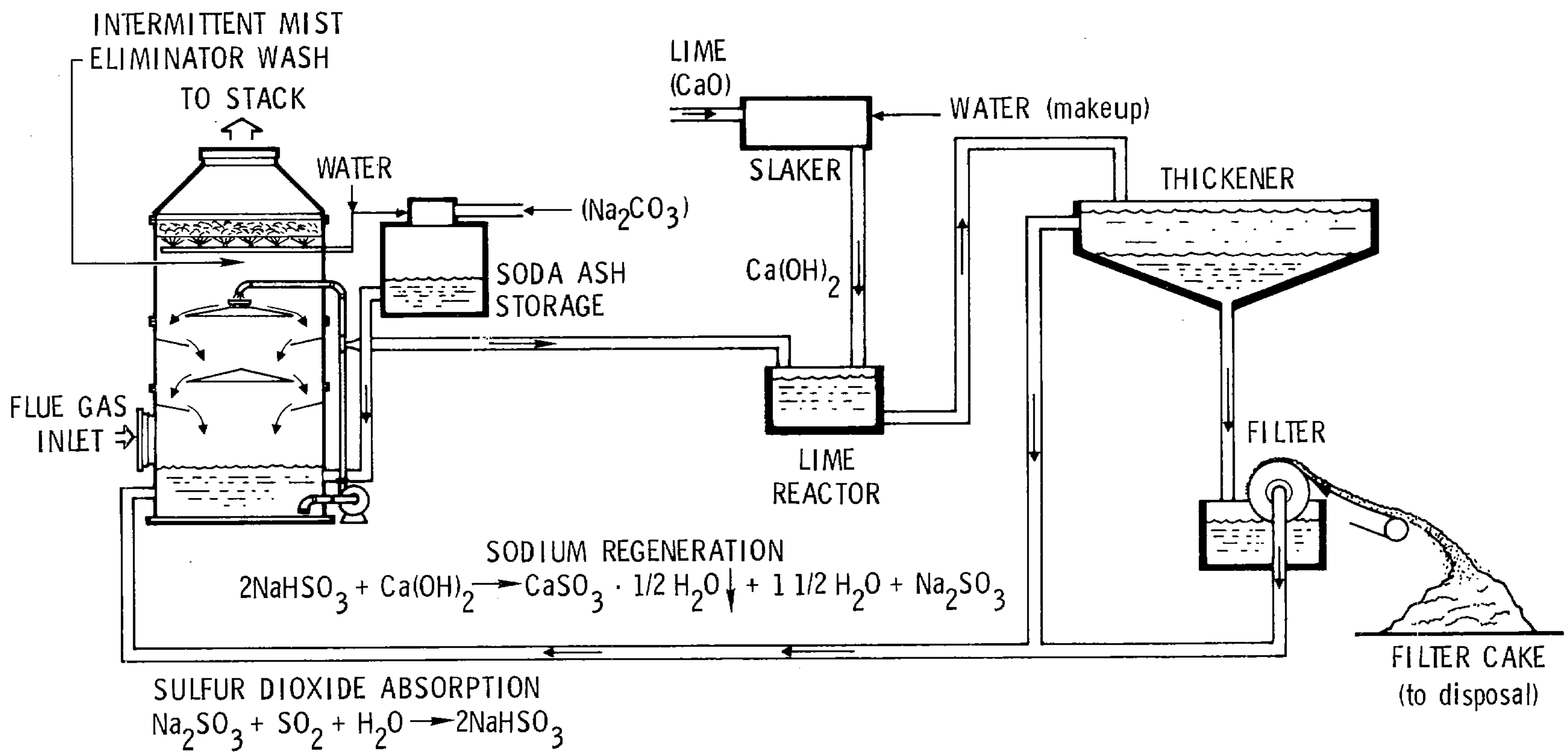


Figure 2. Double alkali process schematic

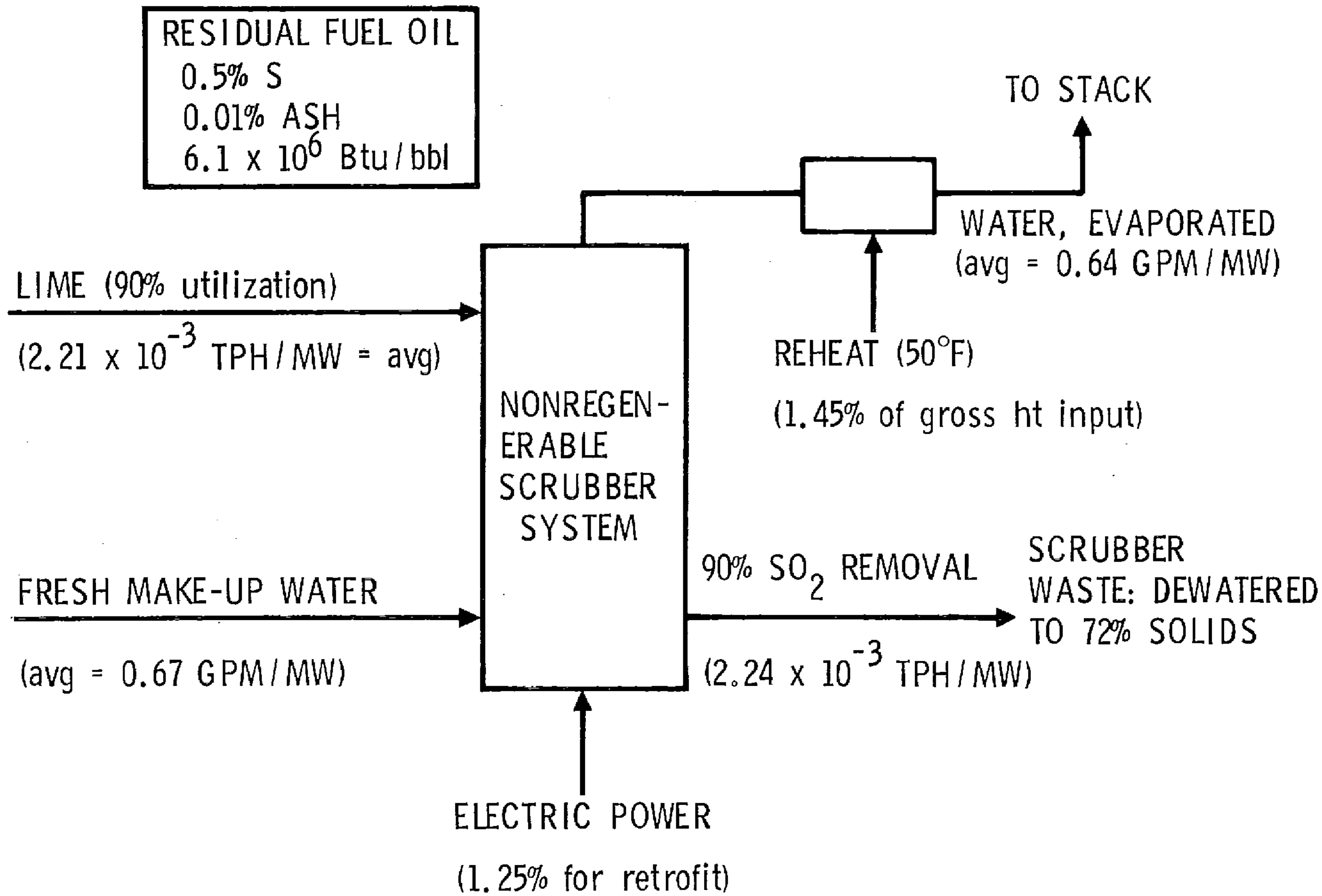


Figure 3. Generalized sulfur dioxide scrubber parameters -- electric utility boilers

TABLE 7. QUANTIFICATION OF SCRUBBER SYSTEM PARAMETERS

| Parameter | Utility | Industrial process |
|---|---|---|
| Number of sites | 8 | 4[a] |
| Total generating capacity, MW | 10,105 | Not applicable |
| Number of units retrofitted | 38 | 8 |
| Annual operation | | |
| Capacity factor | 0.424 | -- |
| Hours | -- | 8,200 (typical) |
| Sulfur dioxide removed annually, tons | 91,100[b] | 9,340 |
| Scrubber waste produced annually | | |
| Tons | 327,800 | 44,500 |
| Acre-feet | 163 | 23.1 |
| Annual lime consumption, tons | 89,000 | 10,500 |
| Current daily fresh water use | | |
| Gallons | 4,510,000 | 1,100,000 |
| Increased consumption--all units, percent | 37 | 22 |
| Annual electric power required, KWh | $469 \times 10^6$ [c] | $44 \times 10^6$ |
| Annual reheat requirement (50°F) | 1.45[d] | $13.0 \times 10^{10}$ Btu |

[a]Fifth site not applicable -- see discussion in Section 4.3.2

[b]90 percent sulfur dioxide removal; fuel oil burned contains 0.5 percent sulfur

[c]Equivalent to 1.25 percent of power generated

[d]Percent of gross heat input

nominal impact on the remaining life of the disposal sites. An operating cost of about $7.14 per ton of disposable dewatered waste was estimated. The conversion of wastes to a useable product and the potential marketability of waste products were not within the scope of this study.

## 2.3 FEASIBILITY OF SCRUBBER INSTALLATIONS

Feasibility of $SO_2$ scrubber installation was based on factors defined for this study and are summarized in Table 3. For the eight utility sites studied, retrofitting of a total of 38 generating units, 41 boilers, with vertical, nonregenerable scrubbers was determined to be feasible on the basis of operating information furnished by the utilities, site visits, plot plans, aerial photographs, and scrubber size and operating information provided by scrubber suppliers. In general, the availability of land and space near the boiler was of primary importance in siting the scrubbers and in determining the resultant complexity of installation (Table 8). While other equipment such as horizontal nonregenerable scrubbers or processes such as those capable of producing sulfur or sulfuric acid might also be feasible at at certain utility sites, the potential optimization, if any, of processes or equipment was not an objective of this study.

For the catalytic cracker carbon monoxide boiler and the process industries installations, retrofitting with scrubbers was found to be feasible (Table 9). Both nonregenerative lime and double alkali processes were considered. Lime scrubbers that are commercially available for industrial applications from a major U.S. supplier that was contacted in this study are provided in discrete modular sizes. In one instance, multiple scrubber units were required and could not be accommodated because of space limitations. In that case, a double alkali system with a single scrubber tower was considered.

One industrial site, the Collier Carbon sulfuric acid plant, Wilmington, California, is operating an ammonia scrubber, which reduces $SO_2$ emissions to approximately 4.7 pounds of $SO_2$ per ton of product. In order to meet the 4.0-pound value, 15 percent $SO_2$ removal would be

TABLE 8. ENGINEERING ASSESSMENT OF SITE-SPECIFIC INSTALLATION FEASIBILITY -- UTILITIES

| Generating station | Capacity, MW | No. of boilers | No. of scrubbers | Retrofit installation complexity[a] |
|---|---|---|---|---|
| Southern California Edison | | | | |
| Alamitos | 1950 | 6 | 10 | Moderate |
| El Segundo | 1020 | 4 | 8 | Difficult |
| Etiwanda | 904 | 4 | 6 | Nominal |
| Huntington Beach | 870 | 4 | 4 | Nominal |
| Redondo Beach | 1310 | 4 | 6 | Difficult |
| | 292 | 7 | 2 | Difficult |
| Ormond Beach | 1600 | 2 | 8 | Moderate |
| Los Angeles Department of Water and Power | | | | |
| Haynes | 1633 | 6 | 10 | Moderate |
| Valley | 526 | 4 | 4 | Nominal |

[a] Based on availability of space and complexity of installation

TABLE 9. ENGINEERING ASSESSMENT OF SITE SPECIFIC INSTALLATION FEASIBILITY -- INDUSTRIAL SITES

| Installation | Unit or plant rating | No. of units | No. of scrubbers[d] | Installation complexity[a] |
|---|---|---|---|---|
| Carbon monoxide boiler -- Chevron | 250,000 lb/hr steam | 1 | 2 | Nominal |
| Petroleum coke calcining kilns | | | | |
| Great Lakes Carbon | 2700 tons/day raw coke | 3 | 3 | Difficult |
| Martin Marietta Carbon | 960 tons/day raw coke | 1 | 1 | Nominal |
| Sulfuric acid units | | | | |
| Stauffer Chemical | 800 tons/day sulfuric acid | 3 | 3[e] | Moderate |
| Collier Carbon | 450 tons/day sulfuric acid | 1 | 1[b] | Nominal[c] |

[a]Primarily based on availability of space

[b]Existing

[c]If additional scrubber is required; see discussion in Section 4.3.2

[d]Double alkali process

[e]Nonregenerable lime process

required. It was determined that the existing scrubber could be operated to meet the study objective of 4.0 pounds. However, some questions were raised about the possibility of increasing plume opacity above current allowables. The scrubber supplier indicated that techniques could be employed to decrease plume opacity if it occurred. In addition, space is available in the event opacity were a problem and a nongenerable scrubber is required.

## 2.4 COST ESTIMATES

Capital, operating, and annualized cost estimates were determined. Capital investment estimates utilized generic scrubber equipment costs for new installations provided by scrubber suppliers. Total capital investment estimates were computed on the basis of a range of retrofit and redundancy factors. Owner total capital investment costs for the utility scrubber installations ranged from an average of $118 to $154 per kilowatt, with an overall average of $135 per kilowatt (late 1977 dollars) (Table 10a). The lower figure includes a 10 percent factor for redundancy and retrofit complexity and represents the lower limit anticipated for a non-complex installation with limited redundancy. The higher value includes significantly greater factors, i.e., 40 percent each. The 10 to 40 percent installation complexity range is estimated as being the range that would encompass those items that cannot be specifically defined unless a detailed engineering study were conducted for each site. They may include relocating underground and surface facilities and installation of complex duct work from the scrubber to existing stack entry locations if a detailed design study were to indicate it was practical or to extend the ducting to new stacks. In estimating capital equipment costs for this study, costs of new stacks were included. These costs are itemized for each utility site in Section 4.5.1.1 and are summarized in Table 11.

The total capital investment for the industrial process scrubbers does not lend itself to a generalization such as dollars per kilowatt. Therefore, the average costs for each site are indicated in Table 11, and the range of retrofit costs in Table 10b.

Average annualized costs were calculated as 8.8 mills/kWh, or $3612 per ton of $SO_2$ removed, for a 20-year expected life for the utility scrubber systems, including 0.062 mills/kWh for scrubber waste transport and disposal. Considering the cost benefit derived from the use of oil with 0.5 percent sulfur, which is approximately $0.70 per barrel less than the fuel with 0.25 percent sulfur which is now in use, the operating cost would

TABLE 10a. TOTAL CAPITAL INVESTMENT FOR UTILITY INSTALLATIONS: RETROFIT AND REDUNDANCY FACTORS INCLUDED

Late 1977 dollars

| Installation | Generating capacity,[a] MW | Average capacity factor, 1976 | Grass roots installation, owner's capital investment, \$/kW[b] (average) | Total capital investment | | | |
|---|---|---|---|---|---|---|---|
| | | | | Maximum[c] \$/kW | Minimum[c] \$/kW | Average[c] \$/kW | Average[d] \$(000,000) |
| Southern California Edison | | | | | | | |
| Alamitos | 1,950 | 0.442 | 91.3 | 138.1 | 103.4 | 120.6 | 235.2 |
| El Segundo | 1,020 | 0.444 | 107.4 | 161.5 | 120.9 | 161.5[e] | 164.7[e] |
| Etiwanda | 904 | 0.498 | 109.5 | 164.7 | 123.3 | 143.9 | 130.1 |
| Huntington Beach | 870 | 0.434 | 108.6 | 163.3 | 122.3 | 142.7 | 124.2 |
| Ormond Beach | 1,600 | 0.454 | 92.7 | 139.4 | 104.4 | 121.8 | 194.9 |
| Redondo Beach | 1,310<br>292 | 0.451[f]<br>0.15 | 100.0 | 150.4 | 112.6 | 150.4[e] | 197.0[e]<br>43.9 |
| Los Angeles Department of Water and Power | | | | | | | |
| Haynes | 1,633 | 0.667 | 89.4 | 134.4 | 100.7 | 117.5 | 191.9 |
| Valley | 526 | 0.158 | 117.4 | 176.6 | 132.3 | 154.3 | 81.2 |
| Average | -- | -- | 102.01 | 153.5 | 115.0 | 134.9[g] | -- |

[a] Total generating capacity 10,105 MW

[b] See Table 63

[c] Maximum capital investment includes +40 percent for retrofit and +40 percent for redundancy
Minimum capital costs include +10 percent for retrofit and +10 percent for redundancy
Average capital costs include +25 percent for retrofit and +25 percent for redundancy

[d] Total capital investment is \$1.363 billion

[e] Maximum retrofit and redundancy factors used because of installation complexity

[f] 0.451 applies to Units 5 through 8; 0.15 applies to Units 1 through 4

[g] Weighted average

TABLE 10b. INDUSTRIAL PROCESS $SO_2$ SCRUBBER CAPITAL INVESTMENT

Late 1977 dollars

| Installation and No. of units | Supplier capital cost estimate, $(000, 000) | Grass roots installation, owner's total capital investment, $(000, 000) | Total capital investment, $(000, 000) | | |
|---|---|---|---|---|---|
| | | | Maximum[a] | Minimum[a] | Average[a] |
| Carbon monoxide boiler--Chevron (1) | 2.6[b, c] | 9.4 | 14.1 | 10.6 | 12.4 |
| Coke kilns--Great Lakes Carbon (3) | 2.8[b, c] (each) | 30.4 | 45.7 | 34.2 | 39.9 |
| Coke kiln--Martin Marietta Carbon (1) | 2.8[b, c] | 10.1 | 15.2 | 11.4 | 13.3 |
| Sulfuric acid units--Stauffer Chemical (3) | 0.78[d] (each) | 8.5 | 12.8 | 9.6 | 11.2 |
| Total | -- | -- | -- | -- | 82.6[e] |

[a] Maximum based on +40 percent retrofit and +40 percent redundancy factors (see Table 65). Minimum based on +10 percent retrofit and +10 percent redundancy factors. Average based on +25 percent retrofit and +25 percent redundancy factors.

[b] Double alkali process

[c] Includes $100, 000 for reheat heat exchanger estimated from Ref. 10. Adjusted to late 1977 dollars.

[d] Lime scrubbing process

[e] Maximum retrofit and redundancy factors used for Great Lakes Carbon installation because of installation complexity

## TABLE 11. SULFUR DIOXIDE SCRUBBER COST SUMMARY

Average costs in late 1977 dollars

| Installation and No. of units | Total capital investment | | Annualized cost, including disposal[a] | | | Approximate product selling price, $ | Percent of selling price |
|---|---|---|---|---|---|---|---|
| | Millions of dollars[b,c] | $/kW | $/ton sulfur dioxide removed | mills/kWh or $/ton of product | Millions of dollars | | |
| Electrical utility sites -- SCE and DWP units (8) | 1,363 | 135 | 3,612[d]<br>3,200[e,f] | 8.8 mills[d]<br>7.8 mills[e,f] | 339.3<br>300.7[e] | --<br>45[g]<br>35[h] | --<br>17<br>22 |
| Carbon monoxide boiler -- Chevron (1) | 12.4 | -- | 3,440 | Not applicable | 3.2 | -- | -- |
| Coke kilns -- Great Lakes Carbon (3) | 45.7 | -- | 2,415 | $19.72 | 11.7 | 110 | 18 |
| Coke kiln -- Martin Marietta Carbon (1) | 13.3 | -- | 1,140 | $13.93 | 3.5 | 110 | 13 |
| Sulfuric acid units Stauffer Chemical (3) | 11.2 | -- | 5,544 | $10.23 | 2.7 | 50 | 20 |

[a] Based on 20-year lifetime of facility

[b] Average value, see Section 4.5.1.1

[c] Maximum retrofit and redundancy factors applied (+40 percent, each) because of installation complexity (others +25 percent, each)

[d] Excluding SCE Redondo Beach Units 1 through 4 and DWP Valley Station. Both are age limited (assumed as 10 yr): annualized costs 32 mills/kWh

[e] Includes 1.0 mill/kWh credit from use of 0.5 percent sulfur oil at $0.70 per barrel less than 0.25 percent sulfur oil

[f] 7.8 mills/kWh equivalent to $5.59/bbl, or $0.91 per million Btu input

[g] Domestic service rate

[h] General service rate

be reduced to 7.8 mills/kWh or $3200 per ton of $SO_2$ removed (Table 11). These costs, however, do not include costs incurred as a result of shutdown of the operating units during scrubber installation.

Comparable annual costs for 20-year life industrial process scrubbers range from $1140 to $5544 per ton of $SO_2$ removed. Other comparisons are shown in Table 11.

For industrial process scrubbers, the effect of paying for scrubber equipment at a faster rate than the 20-year lifetime was determined. If emission source capacity factors remained unchanged, amortizing the capital equipment costs in 5 years instead of 20 would increase the annualized costs by a factor of 1.59.

The effect of remaining life and capacity factor of an electrical generating facility is illustrated by assessing the effect of a 10-year life on the SCE Redondo Units 1 through 4 and the DWP Valley plant. These are old installations and operate at low capacity factors of approximately 15 percent as contrasted to approximately 42 percent for the other units in the study. The average operating cost increases from 8.8 mills/kWh to 31.6 mills/kWh, or $13,500 per ton of $SO_2$ removed (see Section 4.5.2 and Appendix E ).

## 3. RECOMMENDATIONS

Inasmuch as installation of sulfur dioxide ($SO_2$) scrubbers on specific units in the Los Angeles area has been shown to be feasible, certain considerations are of importance regarding the effect of $SO_2$ scrubbing on the industry as a whole, on other environmental control systems, and on the environment itself. Therefore, it is recommended that studies be conducted as follows:

a. Determine the feasibility of installing $SO_2$ scrubbers on other major stationary sources of emissions such as industrial boilers, primary metals and glass furnaces, sulfur recovery units, petroleum process heaters, and oil field recovery vapor phase reactors

b. Determine the effect of wet $SO_2$ scrubbers on the formation of $SO_3$ and on $SO_3$ acid mist emissions

c. With $SO_2$ and $NO_x$ control devices operating simultaneously on utility and other boilers, determine their impact on the feasibility of installation, the interactions of the two systems, the reliability of operation of each control system and of the combined systems, and the total environmental control costs for systems to meet prescribed standards.